Improved Oil Recovery In Fluvial Dominated Deltaic Reservoirs of Kansas

By Rodney R. Reynolds, Don W. Green, G. Paul Willhite, Michael J. Michnick and Dwayne McCune
Tertiary Oil Recovery Project (TORP), University of Kansas

Introduction

Common oil field problems exist in fluvial dominated deltaic reservoirs in Kansas. The problems are poor waterflood sweep efficiency and lack of reservoir management. The poor waterflood sweep efficiency is due to 1) reservoir heterogeneity, 2) channeling of injected water through high permeability zones or fractures, and 3) clogging of injection wells due to solids in the injection water. In many instances the lack of reservoir management results from 1) poor data collection and organization, 2) little or no integrated analysis of existing data by geological and engineering personnel, 3) the presence of multiple operators within the field, and 4) not identifying optimum recovery techniques.

This project involves two demonstration projects, one in a Morrow reservoir located in the southwestern part of the state and the second in the Cherokee Group in eastern Kansas. Morrow reservoirs of western Kansas are still actively being explored and constitute an important resource in Kansas. Cumulative oil production from the Morrow in Kansas is over 200,000,000 bbls. Much of the production from the Morrow is still in the primary stage and has not reached the mature declining stage of that in the Cherokee. The Cherokee Group has produced about 1 billion bbls of oil since the first commercial production began over a century ago. Many of the reservoirs are operated close to the economic limit, although the small units and low production per well are offset by low costs associated with the shallow nature of the reservoirs (less than 1000 ft. deep).

The project is being conducted in a cooperative manner involving University of Kansas scientists, engineers, and geologists and independent oil operators. Different independent oil operators operate the two demonstration sites. The Stewart Morrow Field is located in Finney County, Kansas and is operated by PetroSantander, Inc. This field was in the latter stage of primary production at the beginning of this project and is currently being waterflooded as a result of this project. The Nelson Lease (an existing waterflood) is located in Allen County, Kansas, in the N.E. Savonburg Field and is operated by James E. Russell Petroleum, Inc. The objective is to increase recovery efficiency and economics in these types of reservoirs. The technologies being applied to increase waterflood sweep efficiency are 1) in situ permeability modification treatments, 2) infill drilling, 3) pattern changes, and 4) air flotation to improve water quality. The technologies being applied to improve reservoir management are 1) database development, 2) reservoir simulation, 3) transient testing, 4) database management, and 5) integrated geological and engineering analysis.

Stewart Field Background

The Stewart Field ranges from 0.25 to 0.5 miles wide, is 4.5 miles long and covers approximately 2400 acres. The field was discovered in 1967 with the well being completed in a basal Pennsylvanian Morrow sand from 4755-4767 for 99 BOPD. Only four additional wells were drilled until 1985. Active development of the field took place from 1985 to 1994. Wells produced with minor stimulation until in 1990 and 1991 a field-wide hydraulic fracture program was conducted.

The Stewart Field contains 28^{o}API oil with a small amount of solution gas (37 SCF/bbl). The initial reservoir pressure was estimated to be 1102 psig with a bubble point of approximately 180 psi. The reservoir oil was highly undersaturated and the expected primary production behavior was a rapid decline of reservoir pressure as the reservoir energy in the form of fluid and rock expansion was depleted.

Two field-wide shut-in tests were conducted in 1989 and 1991 to determine reservoir pressure distribution. Pressure tests indicated continuity of the reservoir over the 4.5 mile length of the field. Material balance calculations were performed from the initial reservoir pressure to the average reservoir pressures observed in the 1989 and 1991 field wide tests. Assuming no water influx, the fluid produced should be due to fluid and rock expansion over the given pressure drop. These calculations gave an estimate in excess of 100 million barrels of oil in place. Volumetric mapping of the net sand indicated only 22 million barrels in place.

It was determined that uncertainties in fluid and rock properties would not resolve the difference in determining the original oil in place between volumetric mapping of the net sand and material balance calculations. Either a large volume of the reservoir was yet to be defined or a limited water influx (pressure support) existed within the field. This uncertainty provided motivation for the extensive database development and reservoir study associated with this project.

Stewart Field Results

The Stewart Field project results include design, initiation and operation of a waterflood utilizing improved reservoir management techniques resulting in an increase in oil production rate from 270 to over 3150 BPD.

North American Resources Company (NARCO) was the operator that implemented the waterflood. The waterflood design was based on a reservoir simulation study conducted as part of this project. The original waterflood pattern was a modified six-line drive, resulting from six producing wells being converted to injection. Water injection began on October 9, 1995. In March 1996 oil production in the field began to respond to the water injection. Oil production increased to 1700 BOPD by October 1997 and NARCO sold the Stewart Field waterflood to PetroSantander, Inc., who subsequently converted six additional producing wells to injection. Oil production has continued to increase and as of December 31, 1998 total incremental waterflood response is over 2900 BOPD. Oil production over the life of the field is shown in **Figure 1**. The increase in production rates during the period from 1985-1989 was due to rapid development of the field. Peak primary production rates were observed following the hydraulic fracturing program carried out in 1990 and 1991, followed by a rapid decline in production. Current total field production is over 3150 BOPD. Total incremental waterflood production through December 1998 is 1,634,782 BO.

Savonburg Field Background

This project is comprised of three 160-acre leases totaling 480 acres in Sections 21, 28, and 29, Township 26 South, Range 21 East. The first well drilled in the location of this project was in 1962. Fifty-nine production wells and forty-nine injection wells have been drilled and completed since 1970. A pilot waterflood was initiated in March 1981 and expanded in 1983. Full development occurred in 1985.

In 1986, eleven gel polymer treatments were implemented successfully on the Nelson Lease. Overall incremental oil recovery was 3.5 barrels per pound of polymer placed which totaled 12,500 barrels. The production increase was not sustained due to wellbore plugging as a result of poor water quality.

Savonburg Field Results

This project started in June 1993. Although uncontacted regions of the reservoir were identified, the response to changes in water injection patterns stabilized the decline as shown in **Figure 2**. The principal results from this project is the improvement in the quality of the injection water and corresponding reduction in treating and wellbore cleanup costs.

The injection water at the Savonburg project is a mixture of supply water containing 40 mg/L sulfate and 50 mg/L sulfide and produced water containing 140 mg/L barium and 12 mg/L iron. Barium sulfate and black iron sulfide formed when the two waters were mixed. Before the project started, less than 1000 BPD of water could be processed through the water plant through 75-micron filter bags. Frequent well workovers were required to clean injection wells in order to restore injectivity.

An air flotation unit was developed to remove oil and suspended solids from the injection water. The AFU consists of a 4-foot diameter by 4-foot tall tank. Two venturi tubes are mounted two feet below the surface of the water at a 45^{o} angle to the center of the tank. Clean water from the bottom of the AFU is pumped through the venturi tubes to produce a stream of small air bubbles, which rise, to the water surface, sweeping solids and oil from the water. A high molecular weight cationic polymer flocculation agent is used to enhance the separation. Now 1000 BPD of clean water is routinely processed by a pair of 1-micron filters that last as long as four days before replacement.

The goal for water quality at the Nelson Lease was less than 10 mg/L of suspended solids in the water sent to the field. **Figure 3** illustrates the turbidity measurements made by field personnel for 1998 by date. Note that the goal of less than 10 mg/L was achieved in early May when the 1 SCFM air per 10 gpm feed water was achieved and the waste weir was relocated to the center of the tank.

From July 2 through November 15, the solids in the feed water ranged from 47 to 370 mg/L with an average of 80 mg/L by turbidity (18 mg/L by weight). The solids in the clean water exiting the water plant ranged from 1 to 25 mg/L with an average of 7 mg/L (1.6 mg/L by weight). This corresponds to a decrease in solid content of 90%, which is equivalent to a decrease from 2300 to 200 pounds solids per year sent to the field.

Preliminary cost estimates are $1.25, $2.40, $4.35, and $9.40 per day for cationic polymer, hypochlorite, scale inhibitor, and filters, respectively for 1000 BPD of clean water, or $0.02 per barrel of water. The clean water allowed the replacement of the 75-micron with 5 or 2-micron cartridge filters at each injection well. Cleaner water and better filtration at each injection well reduced the frequency of well cleaning by 50 to 75 percent for additional savings in the waterflood operation at the Nelson Lease.

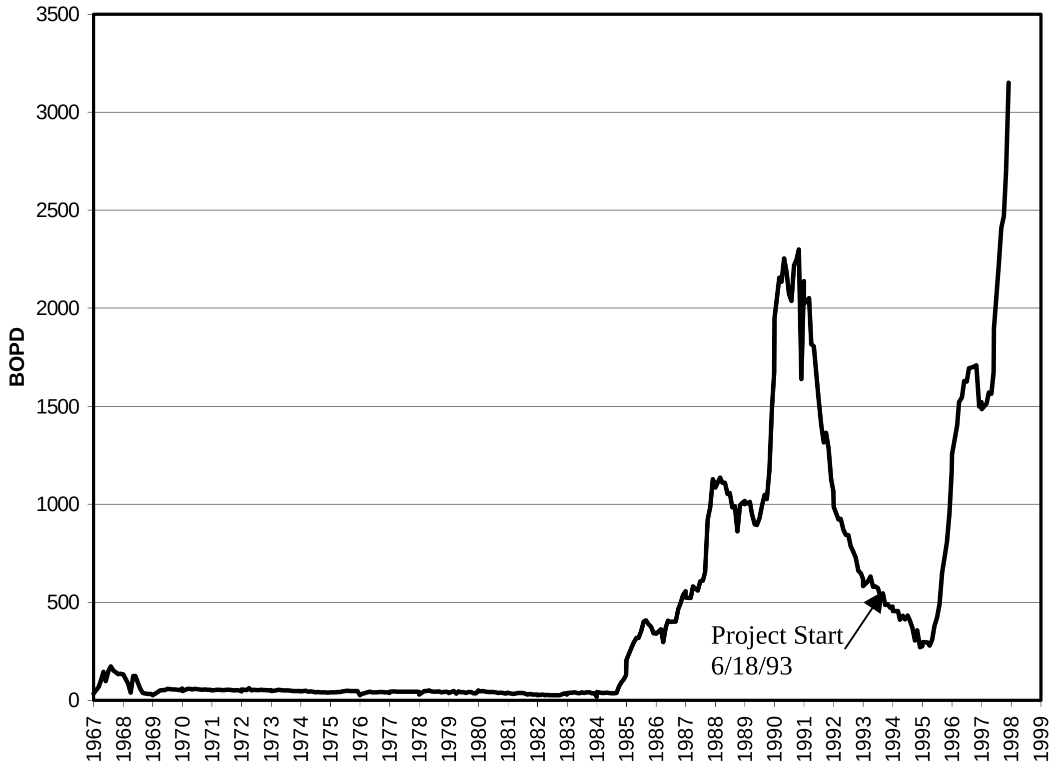

Figure 1. **Stewart Field Oil Production**

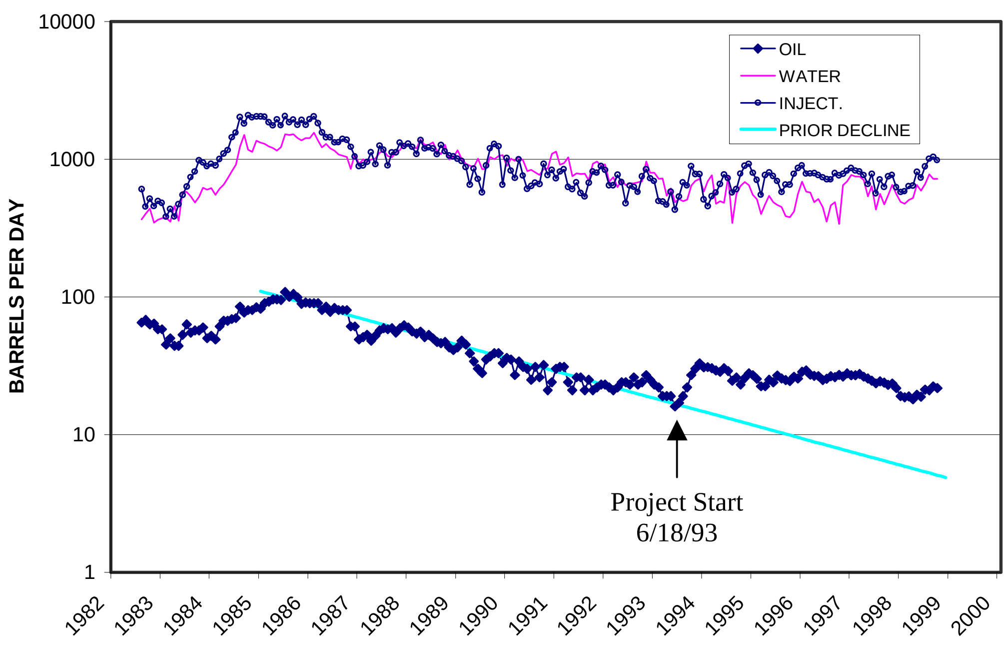

Figure 2. **Savonburg Field Waterflood Production and Injection.**

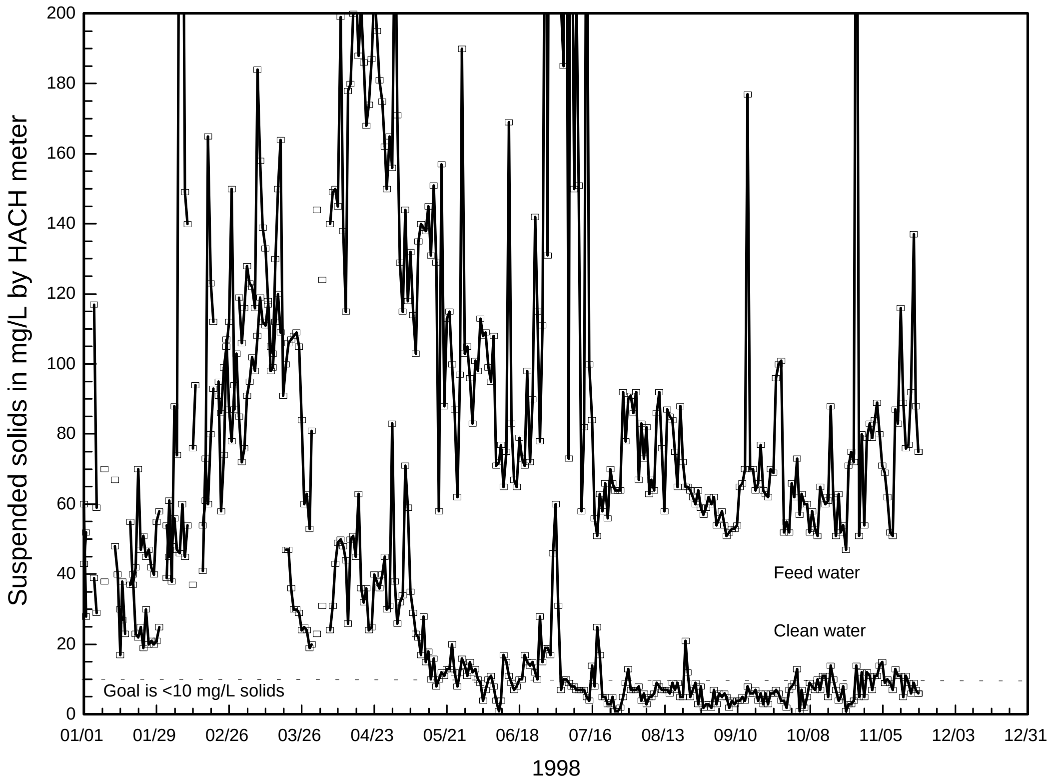

Figure 3. **Savonburg Field Comparison of Suspended Solids Content for Water Entering and Exiting the Air Flotation Unit.**